ERCB

Energy Resources Conservation Board

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News Release

For release 9:00 am, Thursday, 24 November 1983

Calgary, Alberta..... The Energy Resources Conservation Board released today a new report entitled "Alberta Energy '83" which replaces the report "Conservation in Alberta". The new report provides salient information on the status at year-end 1982, historical trends and projections of the energy industry in Alberta.

Sections of the report review highlights of 1982, demand and supply, exploration and development, environmental matters and resource management.

Copies of the report are available without charge at the Board's publication counter.

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Preface

Since 1967, the Energy Resources Conservation Board (ERCB) has published an annual report to the Alberta Legislature and the people of Alberta entitled "Conservation in Alberta". This publication presented information on the energy industry of Alberta and the ERCB's responsibilities and activities in development of the industry.

The ERCB decided to replace "Conservation in Alberta" with "Alberta Energy '83" which (though late this year) normally will be issued in May. This new report provides information regarding the energy industry in Alberta, including its current status and anticipated future trends. A more traditional annual report will also be issued, beginning in 1984, to describe the ERCB's activities during the year under review.

Your suggestions for improvement of the report, to make it more helpful to the readers, would be appreciated. A self-addressed postage-paid reply form is enclosed for your convenience in forwarding us your suggestions.

Introduction

The Energy Resources Conservation Board is charged with resource development and environmental management functions in connection with oil, gas, oil sands, pipelines, hydro and electric energy and coal. These responsibilities include ensuring that energy resources are being developed in an efficient and safe manner, and in the overall public interest, and that environmental standards prescribed by Alberta Environment are met.

A further ERCB responsibility is to make available to the public – including the Alberta Legislature and the energy industry – a wide variety of statistical information to assist in determining the present and future significance of Alberta's energy resources.

Alberta Energy '83 has been prepared with these responsibilities in mind.

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Energy Highlights

. . . a review of Alberta's energy resources in 1982

Most of Alberta's energy resource industries were depressed in 1982 due to the economic recession and to the adverse effects of the National Energy Program (NEP). Under the NEP, revenues to the oil and gas industry were reduced and developmental incentives introduced which caused investment to be diverted to the expensive frontier areas. In turn, this caused a decrease in exploration and development in proven areas having established production.

The sharp drop in consumer demand for refined petroleum products, together with Canada's commitments to buy foreign oil, reduced the demand for domestic crude oil. Alberta's production of conventional crude oil fell to less than 938 thousand barrels (149 thousand cubic metres) per day, the lowest level since 1970. Favourable performance by Alberta's two oil sands plants led to production of 120 thousand barrels (19 thousand cubic metres) of synthetic crude oil per day, a level exceeded only in 1980 when production stood at 126 thousand barrels (20 thousand cubic metres) per day. However, the 1982 production rate did not exceed 70 per cent of plant capacity, providing considerable opportunity in plant performance for further growth.

Remaining established reserves of conventional crude oil continued the decline which began in 1970. These reserves now total only 4.1 billion barrels (649 million cubic metres), their lowest level since 1963, and only 57 per cent of the peak level reached in 1969. Provincial incentive programs, to alleviate the costs of tertiary recovery projects, do offer some possibility of slowing the rate of decline in crude oil reserves. Natural gas production increased modestly, from 6250 to 6420 million cubic feet (176 to 181 million cubic metres) per day in 1982, despite deliveries of additional Canadian gas to the United States through early construction of a part of the Canadian portion of the Alaska Pipe Line. Deliveries in 1982 to the United States were only 51 per cent of the permitted rates, down from 56 per cent in 1981. However, because the permitted rates had been increased, actual exports increased by 11 per cent over 1981. Also, a slight increase in natural gas sales was achieved in Canadian markets.

Export markets for coal were down; however, Alberta's internal demand for subbituminous coal for use in our thermal power plants resulted in a small increase in total coal production.

Remaining established reserves of natural gas and coal continued to increase. Gas reserves now stand at 68.3 trillion cubic feet (1920 billion cubic metres).[1] Coal reserves are up 7.5 per cent, at 18.4 billion short tons (16.7 gigatonnes).

The production of electric energy, almost all of it marketed inside the province, showed the greatest growth among the energy industries, being up almost 7 per cent from 1981.

Electric generating capacity was 5500 megawatts in 1982, unchanged from 1981. Work continued at Keephills, Sheerness and Genesee, all scheduled to add generating capacity to the system in the mid and late 1980s.

Exploration and development activity declined during the year. Oil and gas drilling, which peaked at 7048 wells in 1980, dropped to 5122 wells in 1982 despite the special short-term incentives introduced by the Alberta government. Two major oil sands projects – Alsands in the Athabasca deposit, and Esso Resources at Cold Lake – were deferred indefinitely due to the unfavourable economic outlook, but experimental activity continues.

Although several petrochemical projects were deferred, one new and one expanded methanol plant began production during the year. Development of a metallurgical coal mine by Manalta Coal at Gregg River was completed and construction was started on the Obed Thermal Coal Project by Union Oil. However, total coal exploration declined substantially and some coal development projects were deferred indefinitely.

Growing public concern regarding the environmental impacts of sour gas was heightened by the blowout of a sour gas well near Lodgepole, west of Drayton Valley, and by citizen concern in the Pincher Creek area regarding two local sour gas plants. As a result, ERCB initiated a study by outside specialists into the perceived impacts of gas plants in southwestern Alberta and will hold an inquiry, in late 1983, into the blowout at Lodgepole.

As a direct result of the decline in new investment in the Alberta energy industry, employment also was down during the year. Especially hard hit was the oil and gas service industry. However, in late 1982 the negative employment figures were moderated somewhat by short-term well servicing and drilling incentive programs introduced by the Alberta government.

In January 1983 the ERCB opened the Energeum, a permanent visitor centre designed to involve Albertans of all ages in Alberta's energy story, at its head office in Calgary.

Energeum

1 37. MJ/m^3 basis.

Demand/Supply

. . . how much energy do we need? how much do we produce?

Alberta produces more energy than it consumes. The flow of energy, as oil, gas, coal, bitumen and hydro, to its ultimate use either inside or outside Alberta is shown in Chart 1. A portion of Alberta's total primary energy production (eg: most of its natural gas) is used in a relatively unprocessed form. Other energy resources are consumed in converting a raw resource into other energy forms (eg: coal used to generate electricity).

For reporting purposes in this review, Alberta's energy resource needs are divided into hydrocarbon and electric categories. **Hydrocarbon requirements** are those required for purposes other than the generation of electricity (eg: direct consumption of natural gas or coal, or the conversion of oil into gasoline or gas into petrochemicals). These hydrocarbon requirements are subdivided into

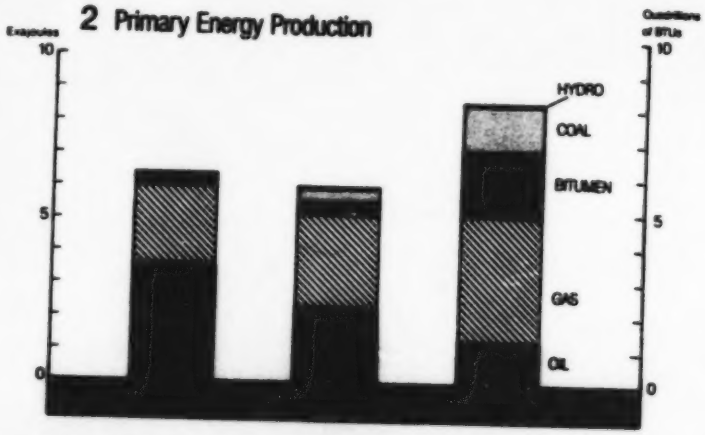
a) those needed to satisfy Alberta's requirements,
b) those needed for conversion into non-energy products (ie: greases and petrochemical feedstocks), and
c) those shipped out of the province in a refined form.

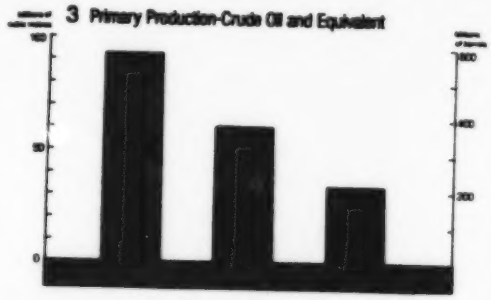
The **electric energy** category is made up of those energy resources used in the generation of electricity. These electric energy resource requirements also are subdivided into

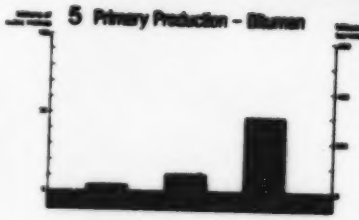
a) the portion delivered as electricity to markets in Alberta, and
b) the portion consumed while making electricity (known as "conversion losses").

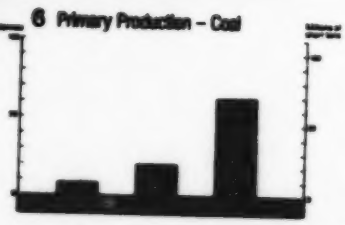
It should be noted that some of the electricity consumed in Alberta is generated on site at industrial facilities. Also, exchanges between provinces may sometimes result in the net import or export of a small amount of electricity in any given year.

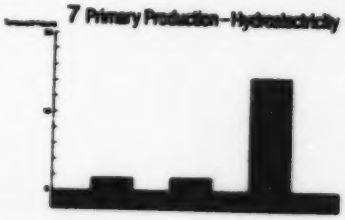
Historical and projected production rates of oil, gas, bitumen, coal and hydro energy are shown in total in Chart 2, and by individual resource in Charts 3, 4, 5, 6 and 7. The sharp increase in production of hydro electricity in the year 2000 (Chart 7) is based on the assumption that large hydro developments proposed at Dunvegan, on the Peace River, and at Mountain Rapids, on the Slave River, will meet approval requirements and be completed by that time.



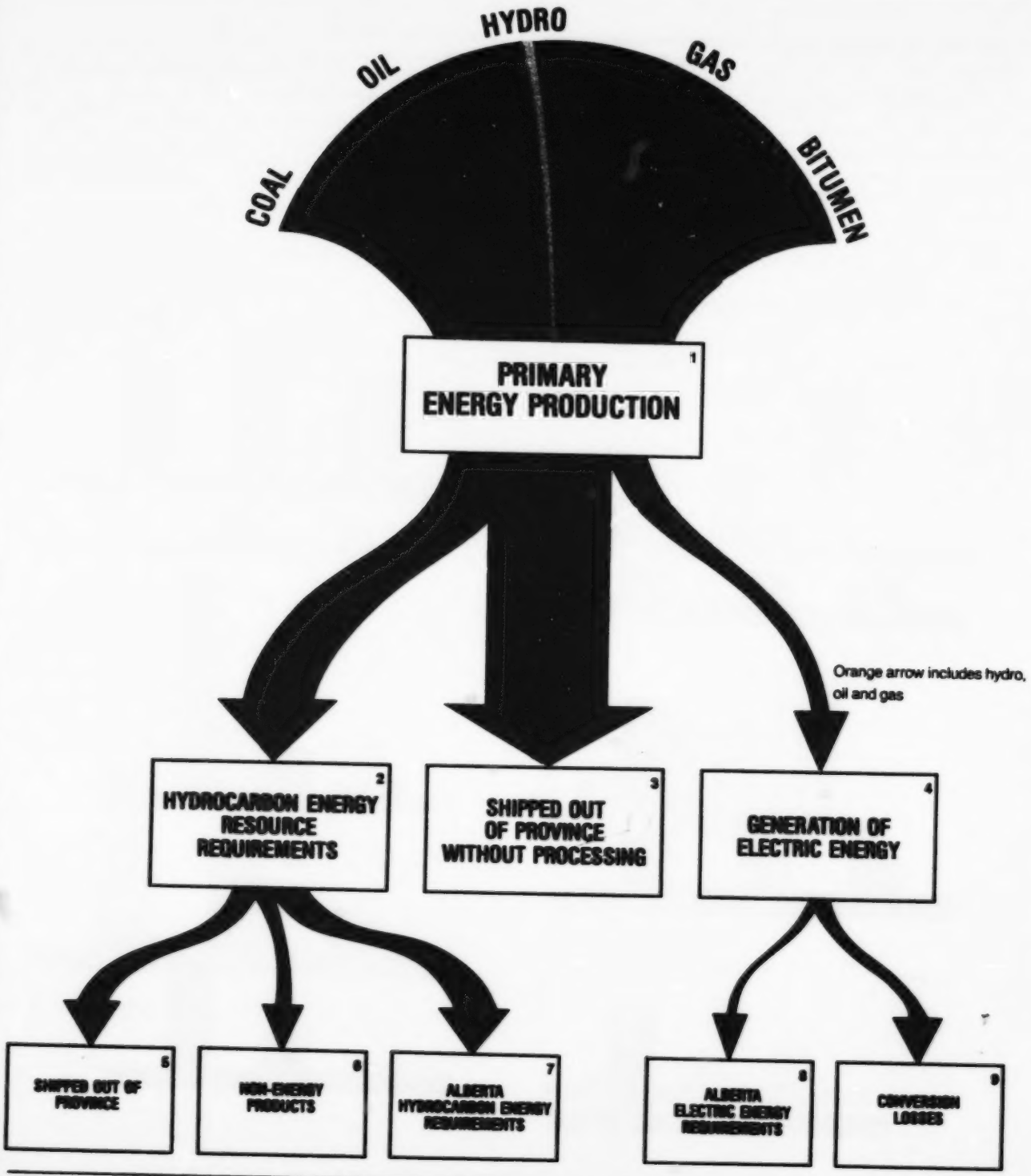








1 Alberta's Energy Flows 1982

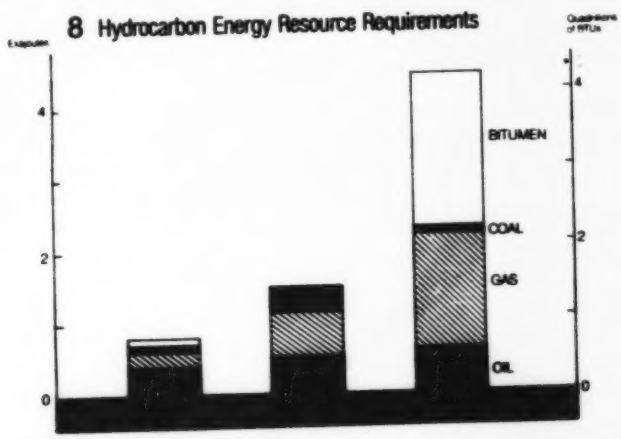


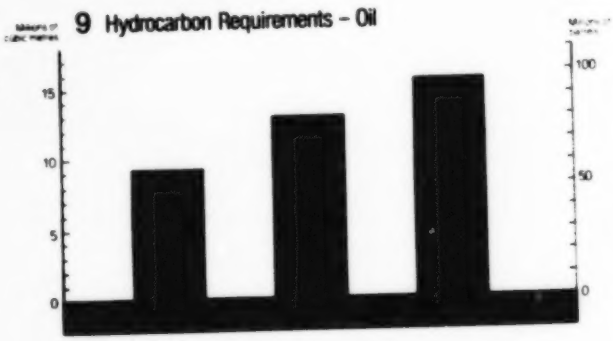
Hydrocarbon energy resource requirements, including oil, gas, coal, bitumen and NGLs (butanes, propane and ethane), are shown in Chart 8, with the historical and projected individual energy resource requirements shown in Charts 9, 10, 11 and 12.

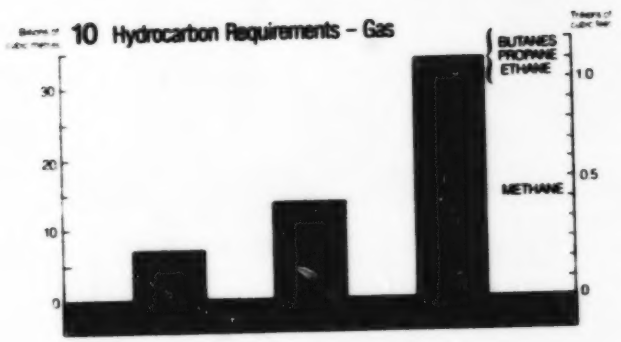
Chart 13 shows the amounts of synthetic crude oil and refined petroleum products which are currently shipped or projected to be shipped out of the province. This chart should be viewed with Chart 16 in determining total oil deliveries to markets outside Alberta.

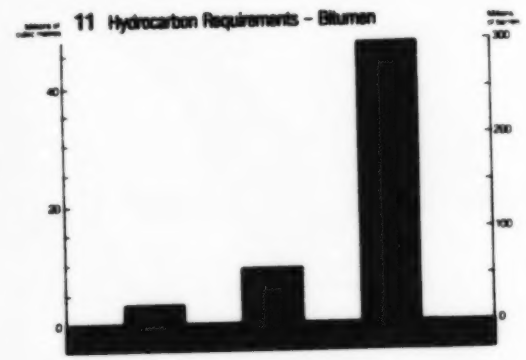
Non-energy product requirements of Alberta (Box 6 of Chart 1) include those products where the energy content is not the critical factor. This includes asphalt, lubricating oils, petrochemical feedstocks and gas used in upgrading bitumen to synthetic crude oil. The historical and projected amounts required are illustrated in Chart 14.

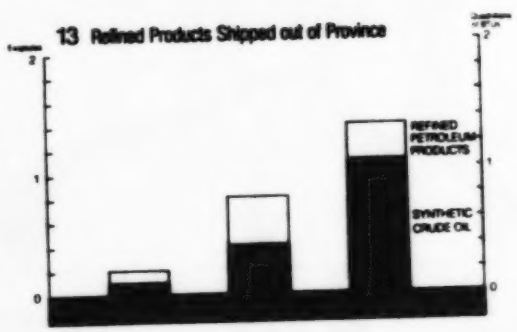
Alberta's hydrocarbon energy requirements (Box 7 of Chart 1) include fuel for refineries and oil sands and petrochemical plants, refined petroleum products used in the province and natural gas consumed in residential, commercial, industrial and transportation facilities. These are compared in Chart 15.











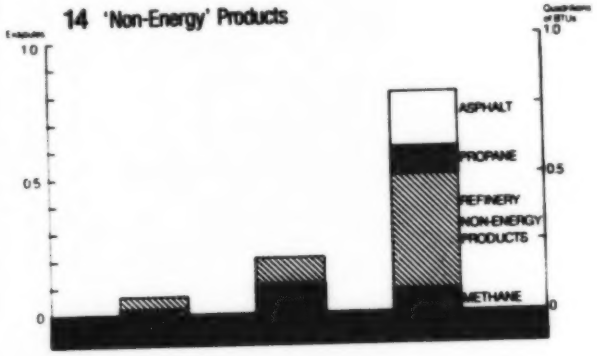
The primary energy shipped, without being processed, and projected to be shipped out of the province is shown in Chart 16. This includes oil, coal, gas, and some bitumen (most of Alberta's bitumen is refined into synthetic crude oil before being sold in Alberta or out of the province. See Chart 13).

Electric energy resource requirements, including all coal, hydro, gas and oil used to generate electricity, are illustrated in Chart 17.

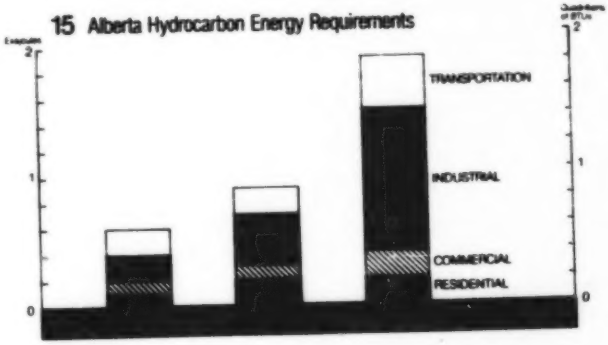
Alberta's electric energy requirements (Box 8 of Chart 1), and conversion losses (Box 9 of Chart 1), are shown in Chart 18. The electricity exchanged with neighbouring provinces each year and the minor amounts of electricity generated at industrial sites are insignificant.

Note: Statistics on energy requirements for the period 1973-1981 were derived from actual values reported to the ERCB by utilities and major consumers. In several instances the 1982 data on requirements are preliminary estimates only. The forecast requirements for the year 2000 are taken from the publication "Energy Requirements in Alberta 1981-2005", ERCB Report 82-F.

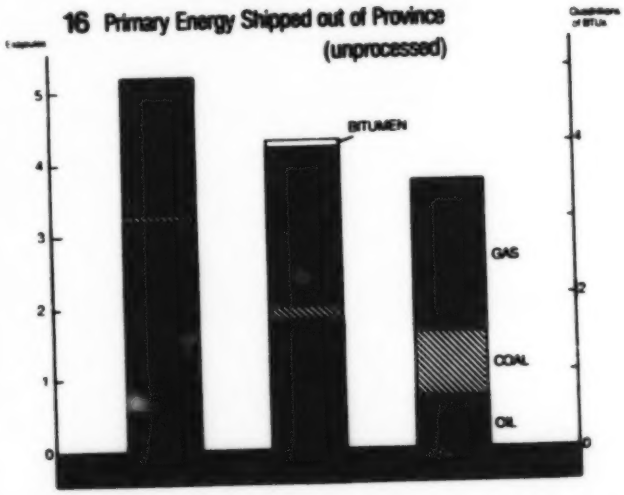
14 'Non-Energy' Products



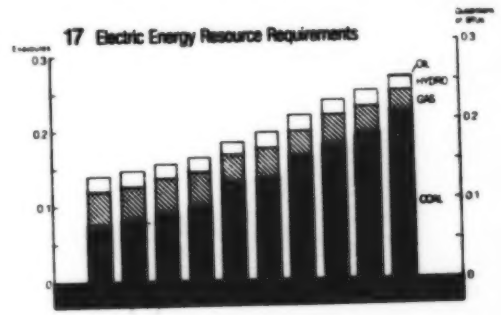
15 Alberta Hydrocarbon Energy Requirements



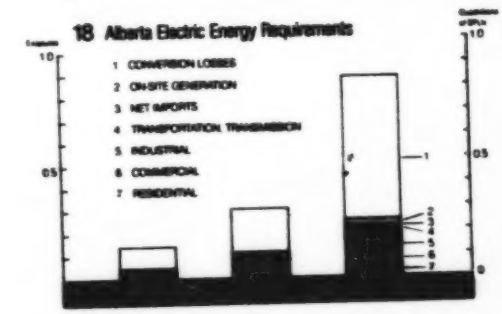
16 Primary Energy Shipped out of Province (unprocessed)



17 Electric Energy Resource Requirements



18 Alberta Electric Energy Requirements



Exploration and Development

. . . looking for and developing energy

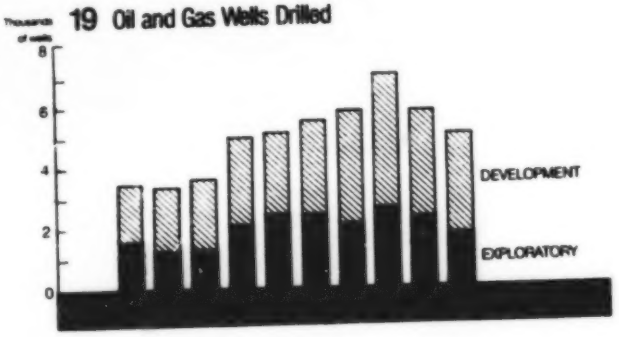
Exploration and development of Alberta's energy resources continued to decline in 1982. Most noticeable effects occurred in the oil and gas sectors.

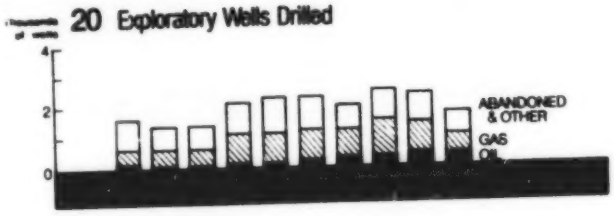
OIL AND GAS

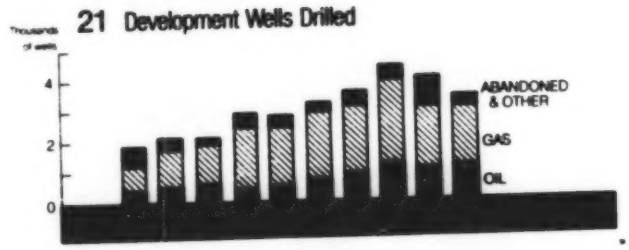
Drilling

The total number of oil and gas wells drilled in 1982 continued the downward trend which began in 1981 (Chart 19), with drilling falling to its lowest level since 1976. The 5122 wells drilled in 1982 represented a 12.5 per cent decline from the total for 1981 and a 27.5 per cent decline from 1980. Exploratory drilling was worst hit (Chart 20), with development wells also declining (Chart 21). Both declines were mainly in drilling for gas.

The poor market outlook for gas and the reduced cash flow and profitability of the industry as a result of the federal Petroleum and Natural Gas Revenue Tax were the main reasons for the decline in activity. These negative factors more than offset the positive effects of the increase in crude oil prices and the province's short-term program of subsidies for development drilling which was introduced in the latter part of the year.







Drilling rig in the Rocky Mountain House area.

Pipelines

Chart 22 shows the cumulative length of pipelines licensed by the ERCB. Since 1972 the total length of pipelines in service has quadrupled. Pipeline construction was especially high in the last half of the decade. The sharp increase, beginning in 1977, was mainly due to Alberta's rural gas program.

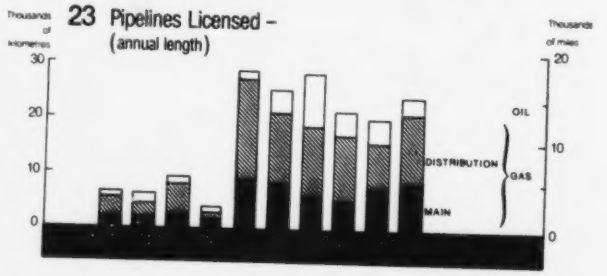
The various categories of pipelines licensed each year from 1973 to 1982 are shown in Chart 23. The lag of six months between construction completion and obtaining a regular licence should be borne in mind when viewing this chart. An ERCB policy decision led to the unusual increases during the 1978-1982 period. Prior to 1975 licences were not required for oil well flow lines (lines from wells to central field facilities). However, in the mid 1970s the ERCB decided, in order to control and improve its records, to formally license these previously unlicensed pipelines. Most of these licences were issued during the 1978-1982 period causing statistics for that period to be artificially high.

Gas Plants

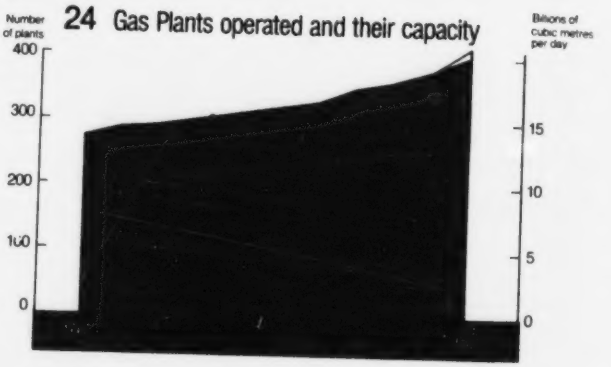
The number of gas plants operating in Alberta increased from 135 in 1972 to 425 in 1982 (Chart 24), with the raw gas processing capacity increasing from 9870 to 14 620 million cubic feet (278 to 412 million cubic metres) per day. Although only 23 per cent of Alberta's remaining established reserves contain hydrogen sulphide, approximately 45 per cent of the raw gas produced in 1982 contained hydrogen sulphide. This gas was processed in 136 plants designed to treat these sour gases.

22 Pipelines Licensed – cumulative length

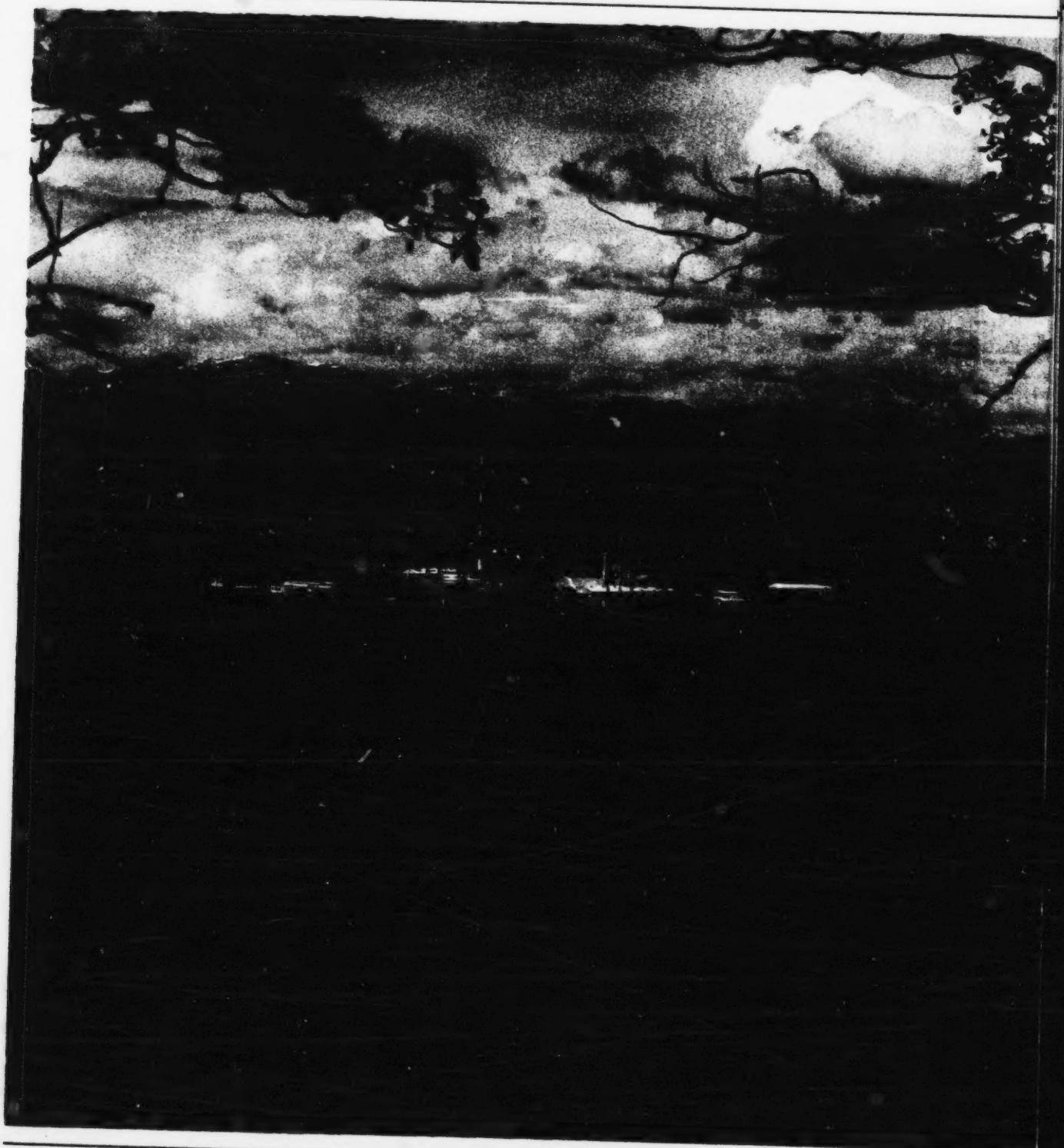
23 Pipelines Licensed – (annual length)



24 Gas Plants operated and their capacity



Shell Jumping Pound Gas Plant



Industrial Plants

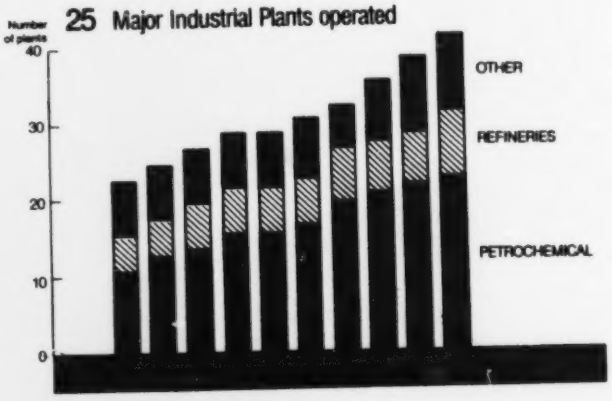
Chart 25 shows the number of petrochemical plants, refineries, and other[2] plants operating in Alberta. Where the expansion of an existing plant required significantly more energy that expansion has been counted as a new plant.

Chart 26 shows the growth in the annual energy requirements of major industrial plants (at their design capacities). Three energy requirements are shown: for fuel, for feedstock and in total. This chart includes only those industrial plants which consume more than 1 petajoule of energy annually as raw material or fuel, or 100 terajoules as raw material (equivalent to 1 billion or 1 million cubic feet of gas respectively).

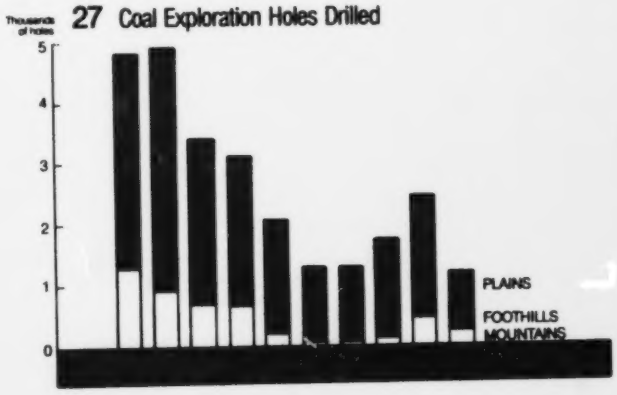
COAL

Coal exploratory drilling activity in all three provincial coal regions declined in 1982 to 1180 holes (Chart 27). This was less than half the level achieved in 1981. Indeed, the 1982 level was among the lowest in the past decade reflecting the depressed outlook for new coal markets. However, some experimental and development activity did continue on new mines.

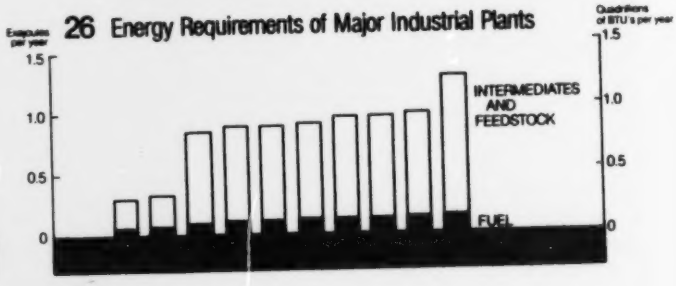
2 Includes two cement plants, two pulp mills, one sugar refinery, one lime plant and one chlorine/caustic soda plant.



25 Major Industrial Plants operated



27 Coal Exploration Holes Drilled



26 Energy Requirements of Major Industrial Plants

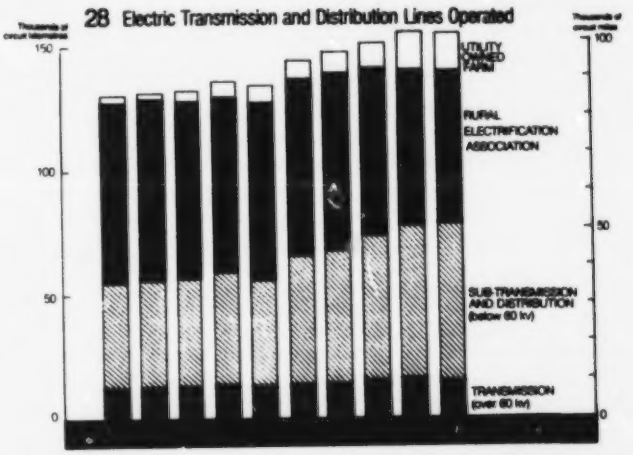
St. Regis (Alberta) Ltd. Pulp and Paper Plant at Hinton.

HYDRO AND ELECTRIC

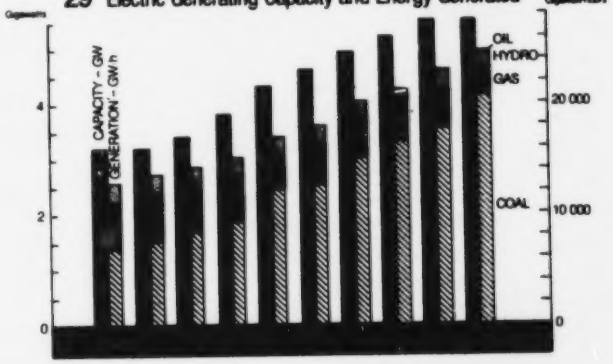
Chart 28 displays the types and lengths of electric transmission and distribution lines operating in the province. There was significant growth in transmission line construction during the middle 1970s (reflecting the commissioning of units at the coal-fired Sundance power plant) but the growth then moderated. This pattern was due, partly, to the gradual shift from gas-fired electric generation near principal centres to mine-mouth, coal-fired power plants. The trend to higher voltages, as Alberta's markets for electricity expanded, was also a contributing factor.

Chart 29 shows the growth in electric generating capacity in the province and energy generated by these facilities. The total capacity has almost doubled since 1972 with most of the increase occurring at coal-fired thermal plants located near central Alberta coal mines.

28 Electric Transmission and Distribution Lines Operated



29 Electric Generating Capacity and Energy Generated



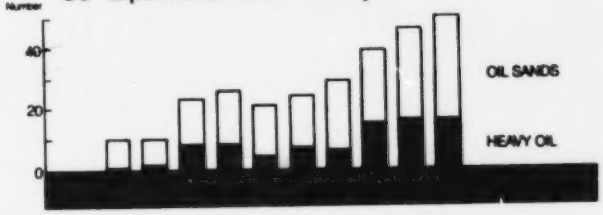
OIL SANDS

Exploration and Experimental Activity

Interest and activity in oil sands and heavy oil thermal experimental oil recovery projects increased steadily during the 10-year period from 1973 to 1982 (Chart 30). The Athabasca and Cold Lake oil sands deposits have been the main areas of interest, but considerable activity also occurred in the heavy oil areas – especially during the last three years at Lloydminster, Morgan and Lindbergh.

Total annual production of crude bitumen and heavy oil from these experimental projects increased from 450 thousand barrels (71.2 thousand cubic metres) in 1973 to 8 million barrels (1281 thousand cubic metres) in 1982. The number of experimental wells increased from 300 to 1300 during the same period.

30 Experimental Scheme Activity



TransAlta Keephills Thermal Generating Plant in the Lake Wabamun area.

Environmental Matters

. . . how energy developments affect the environment

Energy resource developments invariably produce a number of environmental effects, particularly on the land surface and to the atmosphere. The principal land surface effects considered here are those resulting from oil and gas, oil sands, hydro and electric and coal operations. They are produced by well and pipeline incidents, other kinds of liquid spills, by oil sands and coal excavations, by waste materials disposal and by construction and servicing of energy resource facilities. The emissions to the atmosphere from gas processing, crude bitumen processing and thermal electric plants are discussed as well.

FLUID RELEASE INCIDENTS

The most significant sources of environmental impact from conventional oil and gas operations are fluid releases associated with well and pipeline failures and other liquid spills. Sulphur dioxide and other emissions, especially from gas plants, are dealt with separately.

Oil and Gas Well Incidents

Well failures range from minor incidents to a few very serious failures involving environmental damage, injury to workers, substantial costs to the well owners and extensive loss of valuable resources. For statistical purposes major failures are classified either as "blowouts" or "uncontrolled blows".

A blowout is defined as a complete loss of control at a drilling well. This costly and serious incident can cause injuries, fatalities, fires, explosions, serious damage to equipment or property and environmental pollution.

Uncontrolled blows are similar to blowouts except that they occur after wells have been drilled and are characterized by complete loss of control at a producing, suspended or abandoned well.

Under these conditions control can only be regained by the installation and use of special equipment or by drilling a relief well.

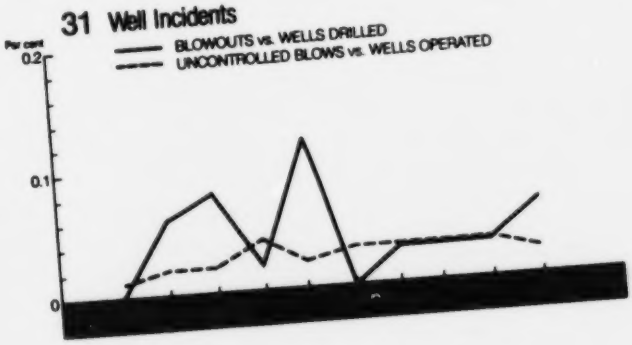
During the last ten years 22 blowouts have occurred in Alberta while drilling approximately 50 thousand wells. These blowouts resulted in 2 fatalities and 24 injuries, environmental damage and loss of resources and equipment.

Historically, the ratio of blowouts to wells drilled has decreased (Chart 31). This reduction resulted from improvements in manpower training and equipment which have, in turn, improved the petroleum industry's capabilities in maintaining adequate well control during drilling.

Uncontrolled blows occurred more frequently than blowouts during the last ten years. There were 67 such incidents in Alberta, leading to 1 fatality, 12 injuries, considerable equipment loss and a number of undesirable environmental impacts. Thirty-three of these incidents occurred during well-servicing operations. Thirty-four occurred during routine producing operations or on wells where operations had been suspended. During this 10-year period, the number of active wells in the province increased from 27 thousand to 67 thousand.

Historically, the ratio of uncontrolled blows to wells operated has not fluctuated much (Chart 31). On an annual average, one uncontrolled blow occurred for every 7000 active wells.

31 Well Incidents



Pipeline Leaks and Breaks

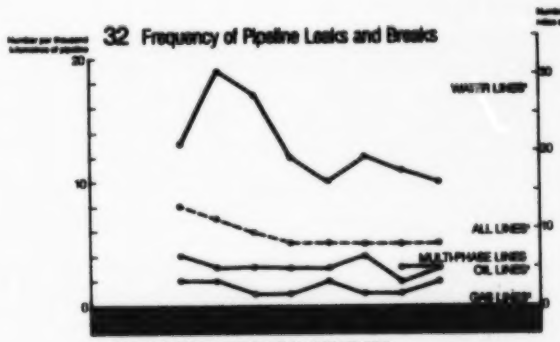
One measure of overall pipeline performance is the frequency of pipeline failures which, in general terms, includes all leaks and breaks. The ERCB requires pipeline operators to report all pipeline leaks and breaks no matter the cause, magnitude or consequence. Thus, although pipeline failure rates may appear to be high in Chart 32, they actually represent minimal environmental damage in total. The relatively few really serious pipeline breaks can have considerable environmental impact, although fluid loss usually is of short duration. These impacts are further discussed under liquid spills and atmospheric emissions.

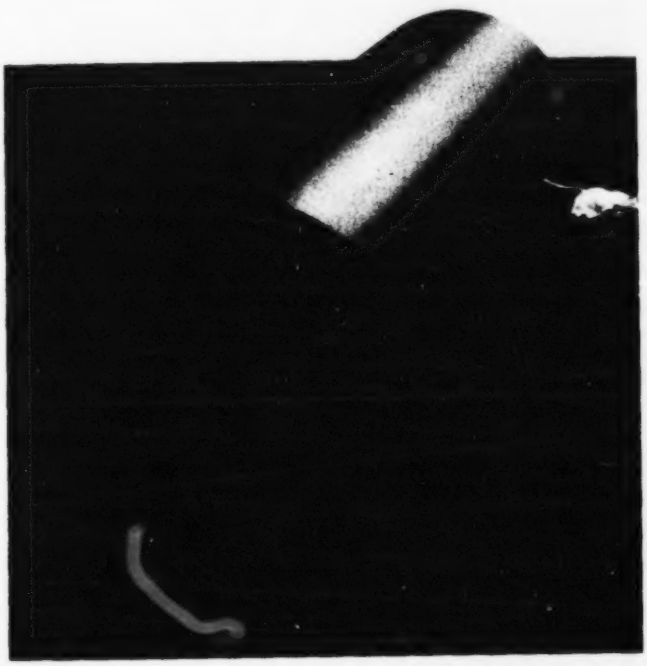
The frequency of pipeline leaks and breaks during the 1975-1982 period is shown in Chart 32, categorized by the type of fluid transported in the pipe. Since 1975 the frequency of these incidents has decreased from eight to five per 1000 kilometres (620 miles) of operating pipeline. Leaks, by pipeline category, fluctuate from year to year. In 1982, as in most previous years, the majority of these leaks occurred on multiphase lines[3] (flow lines) and water lines, each contributing about one-third of the total.

Chart 33 shows the distribution of pipeline leaks and breaks in 1982 by major cause, with about half due to corrosion. This was unchanged from recent years. Leak occurrences due to corrosion increase as the length of pipelines in operation increases and as the lines become older. However, the frequency of water line corrosion leaks has not changed since 1975 and remains at eleven per 1000 operating kilometres (620 miles) per year. In 1982 there were five leaks due to corrosion per 1000 kilometres (620 miles) of multiphase lines.

Pipeline ruptures caused by third-party activity, usually construction equipment used on other projects, accounted for 12 per cent of all 1982 pipeline leaks and breaks. The Pipeline Act has been amended recently with a view to increasing precautionary measures and reducing such third-party damage. Leaks due to other causes (Chart 33) occurred less frequently in 1982 on all types of pipelines. However, they are of concern and are being dealt with through improvements to pipeline design, installation and operating practices.

32 Frequency of Pipeline Leaks and Breaks





3 Pipelines containing oil, gas and water, or any combination of the three.

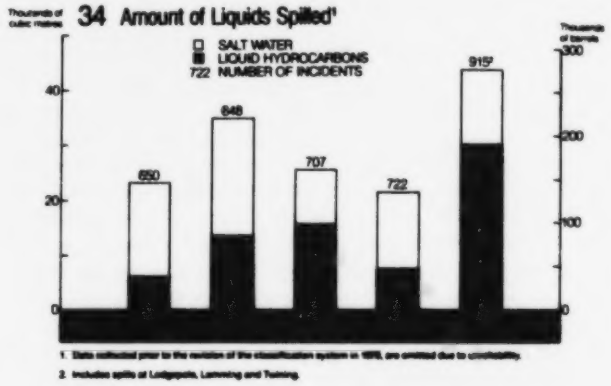
Liquid Spills

Liquid spills from oil and gas facilities include spills of hydrocarbons[4], salt water and other water-based materials, including drilling mud, fresh water, fracturing water, process water, acid and cement. Considerable damage may result and, in some cases, may require years to fully correct.

Chart 34 focuses on hydrocarbon and salt water spills for the period 1973-1982. These spills resulted from failure of wells, pipelines and other facilities.

During the period 1973-1982 liquid hydrocarbon spill volumes have ranged from a low of 38 thousand barrels (6 thousand cubic metres) in 1978 to a high of 190 thousand barrels (30 thousand cubic metres) in 1982. These spills mainly resulted from well blowouts, internal and external corrosion of pipelines, equipment failures and operator error. The high hydrocarbon spill volume in 1982 was due largely to three major incidents.[5]

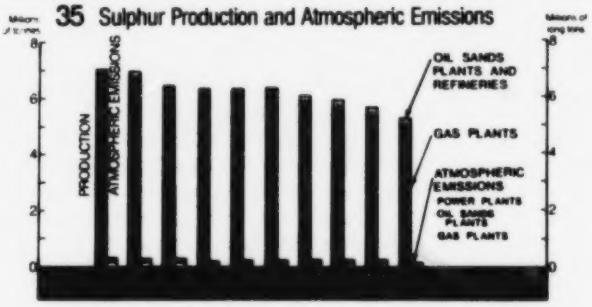
In recent years salt water spill volumes have ranged from a low of 63 thousand barrels (10 thousand cubic metres) in 1980 to 132 thousand barrels (21 thousand cubic metres) in 1979. These spills were mainly the result of internal corrosion of pipelines and other equipment failures.



SULPHUR PRODUCTION AND ATMOSPHERIC EMISSIONS

Chart 35 shows total sulphur production and emissions from gas plants, oil sands plants and coal-fired power plants during the period 1973-1982. Total emissions of this type declined in the early 1970s and have remained stable in recent years. Emissions from gas plants declined, while those from oil sands plants and coal-fired power plants increased.

Alberta's standards for sulphur emissions are among the toughest in the world. They are reviewed periodically to ensure that they remain that way. Equally tough standards control the emissions of nitrogen oxides and fly ash.



4 Condensate, crude oil, diesel fuel, fracturing oil, gasoline, glycol, synthetic crude oil, natural gas liquids, heating oil, kerosene, lubricants, solvent and other similar products.

5 Each releasing greater than 1000 cubic metres.

Gas Plants

Gas plants presently are the largest source of sulphur production and emissions in the province. However, over the past decade the sulphur included in the raw gas being processed at gas plants declined from 6.9 million long tons (7 million tonnes) annually to 4.9 million long tons (5 million tonnes), reflecting the trend towards sweet gas shown in Chart 36.

Sulphur emissions have also been reduced through more stringent sulphur recovery requirements. Overall, the proportion of sulphur recovered at gas plants has increased from 96.1 per cent in 1973 to 97.5 per cent in 1982. The sulphur recovered at Alberta gas plants has consistently exceeded the aggregate sulphur recovery required in ERCB plant approvals.

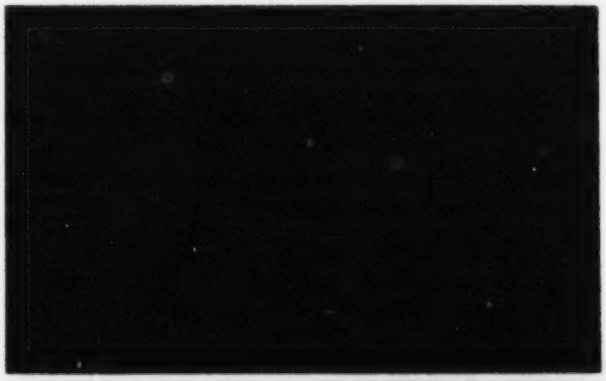
Oil Sands Plants

Sulphur emissions from oil sands plants increased from 52.1 thousand long tons (53 thousand tonnes) in 1973 to 82.7 thousand long tons (84 thousand tonnes) in 1980. This reflected, in large part, the 1978 start-up of Syncrude and the 1981 expansion at Suncor.

Overall sulphur recovery at oil sands plants has increased from 58 per cent in 1973 to 63 per cent in 1982. Eight per cent of the total sulphur contained in the processed bitumen leaves the plants in the coke by-product and 3 per cent in the synthetic crude oil. The remaining 26 per cent is emitted to the atmosphere as sulphur dioxide. The sulphur recovered at the sulphur recovery sections of oil sands plants has increased from 94 to 96 per cent of the sulphur content of the inlet stream. The overall sulphur recovery design efficiency at both Alberta oil sands plants is 72 per cent. However, this level of recovery has not yet been achieved at either plant on a regular basis because of operating problems.

Power Plants

Almost all the coal used to fuel power plants in Alberta is low in sulphur content. The total amount of sulphur emitted annually from Alberta's coal-fired power plants increased significantly, from 10.5 thousand tonnes in 1973 to 31 thousand tonnes in 1982 as the number and size of such plants continued to expand to meet Alberta's electric energy requirements.



Resource Management

. . . how Alberta optimizes its resources

RESOURCE RECOVERY

Enhanced Recovery of Oil

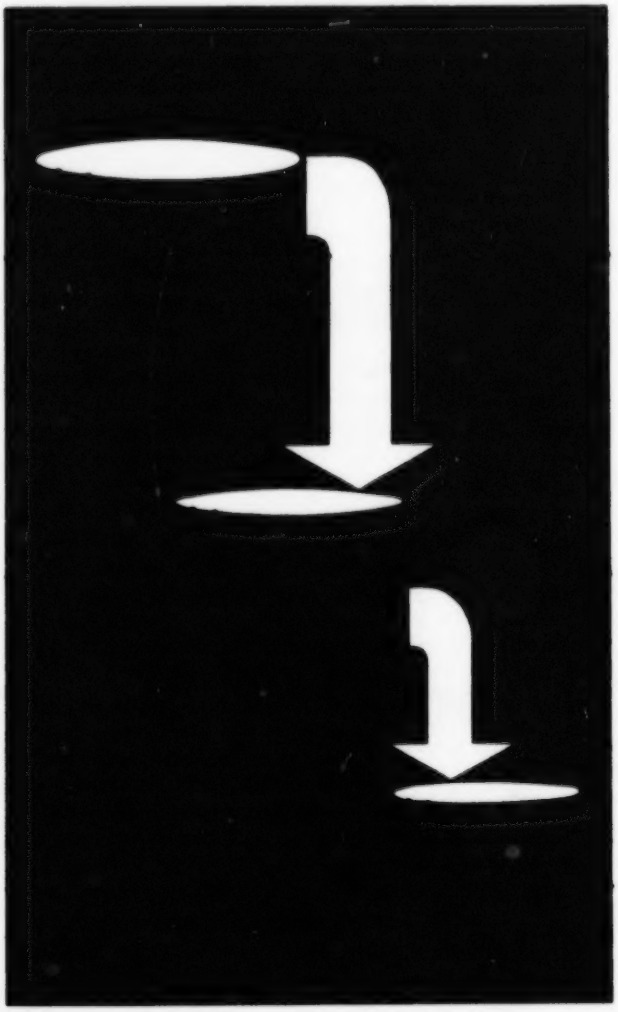
During the early life of a petroleum reservoir the oil is produced by the natural energy in the reservoir. These natural energy drive mechanisms push the oil to the surface. They include solution gas, water, gas cap or any combination of these.

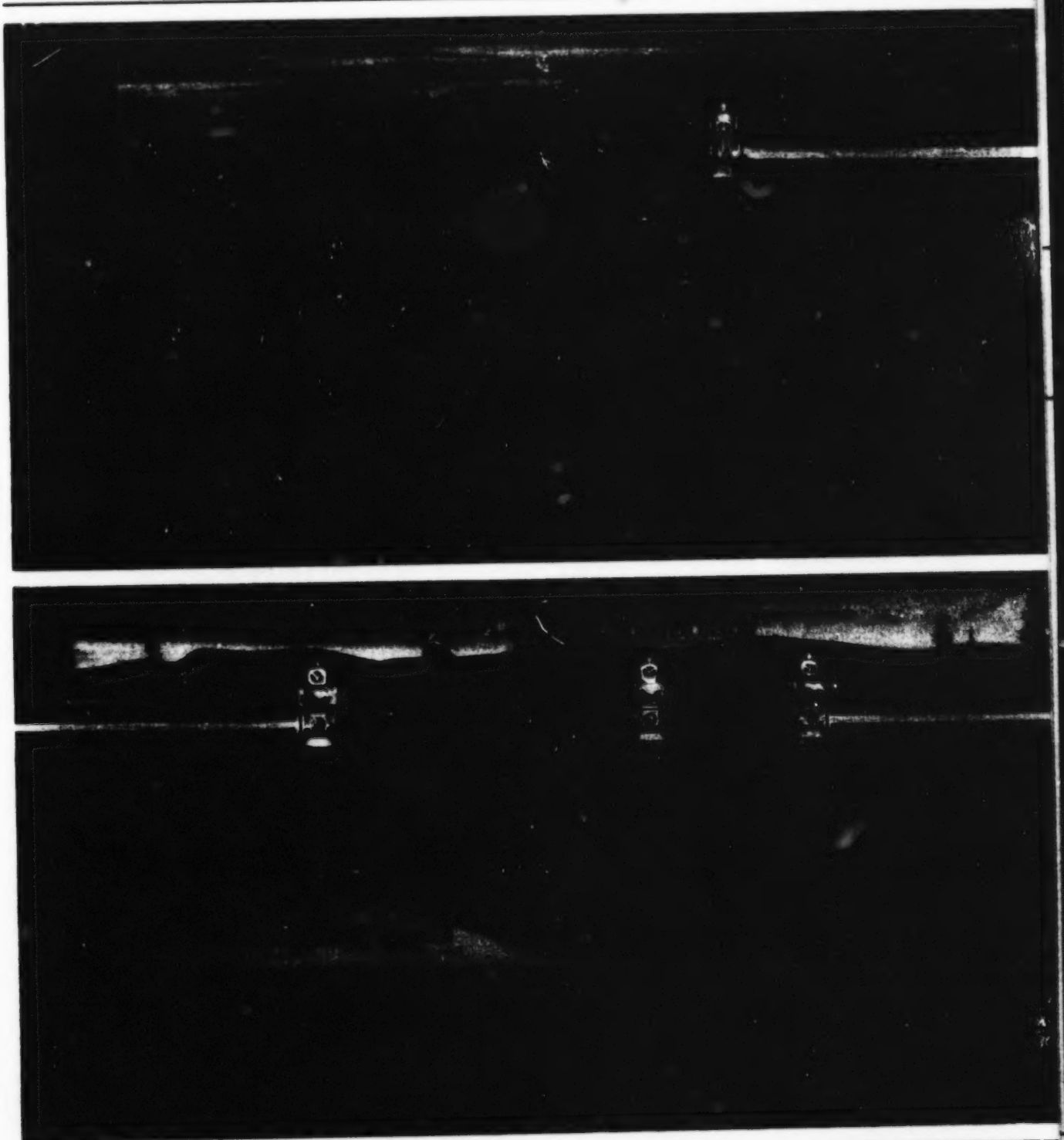
Reservoir engineers must first determine the natural energy sources available in the reservoir, the reservoir rock and fluid characteristics which affect oil recovery and the productivity of each pool. They then establish when the natural drive mechanism of the reservoir must be supplemented and select the most effective enhanced-recovery method. The natural energy is supplemented by injecting fluid into the oil reservoir. Water is the most commonly used injectant since it is usually inexpensive, readily available and reasonably effective in most Alberta pools. Solvent (ie: liquefied petroleum gases and natural gas) is the next most commonly used injectant. Such enhanced-recovery operations may increase the ultimate crude oil recovery by as much as 50 per cent.

Chart 37 shows that to year-end 1982, 42.3 billion stock tank barrels (6.72 billion cubic metres) of crude oil in place have been found in Alberta. Of the total, 29 per cent is recoverable; approximately 20 per cent by natural depletion mechanisms and 9 per cent through enhanced-recovery operations. Chart 39 shows the growth in Alberta's crude oil resources since 1973.

Average recoveries of 32 per cent for light-and-medium crude oil reserves, and 10 per cent for heavy-density conventional crude oils, are being achieved through natural and enhanced-recovery methods. Of course, the application of more complex recovery methods may yield additional oil. However, these methods are much more costly and are feasible only in good reservoirs when economic conditions are favourable.

In 1982 the Alberta Department of Energy and Natural Resources introduced changes to its regulations to encourage the use of sophisticated enhanced-recovery programs. This action has increased the interest in such projects despite the poor outlook for world crude oil prices.





Conservation of Solution Gas

Solution gas is the gas which is released from crude oil as it is brought from the reservoir to the surface. In some reservoirs gas cap gas also may be produced with the oil unintentionally. Where applicable, such gas cap gas normally would be included in the solution gas production data.

Chart 38 illustrates the progress made during the last ten years in conserving solution gas. Solution gas conservation has increased from 87 per cent in 1973 to 91 per cent in the period 1977-1982. The high level of conservation in recent years has been achieved through the co-operative efforts of the producers and the ERCB. Also, extension of pipeline facilities and increases in gas and co-product prices have made it economical to conserve solution gas from smaller oil fields.

SUPPLY CAPACITY

Conventional Crude Oil and Pentanes Plus

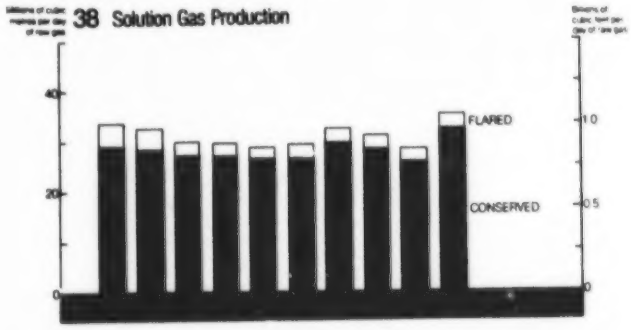
Initial established reserves of conventional crude oil increased by 43 million barrels (6.9 million cubic metres) in 1982 (Chart 39). Production totalled 337 million barrels (53.6 million cubic metres) for the year. This resulted in a net decrease in remaining established reserves of 294 million barrels (46.7 million cubic metres) to 4084 million barrels (649 million cubic metres) at year-end.

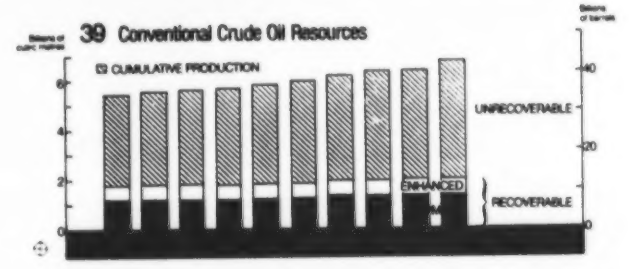
Initial established reserves attributed to enhanced recovery declined by 86.2 million barrels (13.7 million cubic metres) for the year. This figure includes an addition of 41.5 million barrels (6.6 million cubic metres) for new enhanced-recovery methods and a reduction of 127.7 million barrels (20.3 million cubic metres) from re-evaluation and downgrading of existing schemes. The corresponding reserves resulting from natural depletion mechanisms increased by 129.6 million barrels (20.6 million cubic metres), with 105.7 million barrels (16.8 million cubic metres) coming from the discovery of new pools and 23.9 million barrels (3.8 million cubic metres) from the re-evaluation of existing pools.

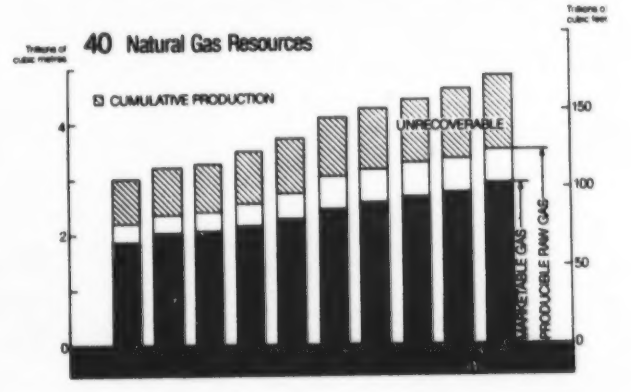
The ultimate potential of Alberta's conventional crude oil is about 16.4 billion barrels (2.6 billion cubic metres), of which 75 per cent has been proven and 50 per cent already has been produced. The remaining ultimate potential is now estimated to be 8.2 billion barrels (1.3 billion cubic metres).

The production of 938 thousand barrels (149 thousand cubic metres) of crude oil per day in 1982 was approximately 91 per cent of productive capacity. At this producing rate the remaining conventional reserves would last about 12 years. The ERCB expects the productive capacity of conventional crude oil to decline to 500 thousand barrels (80 thousand cubic metres) per day by the year 2000.

Pentanes plus comprise the heaviest liquids recovered in processing natural gas. Pentanes plus production in 1982 totalled 96.9 thousand barrels (15.4 thousand cubic metres) per day and is expected to decline to 88 thousand barrels (14 thousand cubic metres) per day by the year 2000.







Crude Oil (and equivalent) from Oil Sands

Initial established reserves of synthetic crude oil from oil sands increased by 315 to 24 900 million barrels (50 to 3950 million cubic metres) in 1982. Production in 1982 totalled 44 million barrels (7 million cubic metres), resulting in remaining established reserves of 24 500 million barrels (3900 million cubic metres) at year-end.

The ultimate potential of synthetic crude oil is estimated to be 189 thousand million barrels (30 thousand million cubic metres). Three hundred and thirty three million barrels (53 million cubic metres) have been produced to date. Thus, supply will not be limited in the foreseeable future.

Oil sands synthetic crude oil production was 120 thousand barrels (19.1 thousand cubic metres) per day in 1982. This rate of production is expected to increase to 240 thousand barrels (38 thousand cubic metres) per day in 1990 and to more than 630 thousand barrels (100 thousand cubic metres) per day in the year 2000.

Synthetic crude oil, conventional crude oil and pentanes plus are marketed together as an oil stream. The total productive capacity of the full stream was 1240 thousand barrels (197 thousand cubic metres) per day in 1982 and is expected to decline to 975 thousand barrels (155 thousand cubic metres) per day in the late 1980s. It is then expected to increase again to 1185 thousand barrels (188 thousand cubic metres) per day in the year 2000. At that time the additions to synthetic crude oil production from the oil sands will more than offset the decline in conventional crude oil and pentanes plus production.

Marketable Gas

The initial established reserves of marketable gas increased by 4370 billion cubic feet (120 billion cubic metres) in 1982 to 102 trillion cubic feet (2990 billion cubic metres). Chart 40 shows that production totalled approximately 2.2 trillion cubic feet (63.4 billion cubic metres) for the year. This resulted in a net increase in remaining established reserves of 2120 billion to 68.3 trillion cubic feet (60 billion to 1920 billion cubic metres).

The ultimate potential is 135 trillion cubic feet (3800 billion cubic metres) of marketable gas. Seventy-nine per cent is established and 28 per cent has been produced already. The remaining ultimate potential is 97 trillion cubic feet (2730 billion cubic metres).

The average 1982 production rate of 6420 million cubic feet (181 million cubic metres) per day is approximately 60 per cent of Alberta's productive capacity. Because of inadequate markets full productive capacity will not likely be reached for some time. The productive capacity is expected to peak about 1990 at 13.5 billion cubic feet (380 million cubic metres) per day and then decline to 7.8 billion cubic feet (220 million cubic metres) per day by the year 2000.

Coal

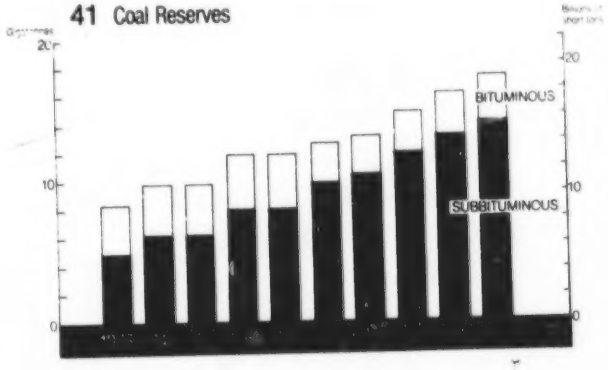
As shown in Chart 41 the initial established reserves of raw coal increased in 1982 by 1.1 gigatonnes to 17.1 gigatonnes (3.6 and 13.5 gigatonnes of bituminous and subbituminous coal, respectively). Production totalled 23.0 megatonnes, resulting in remaining established reserves of 16.6 gigatonnes at year-end, an increase of 1.0 gigatonnes over 1981. The remaining established reserves comprise 3.3 and 13.3 gigatonnes of bituminous and subbituminous coal, respectively.

The ultimate potential of Alberta's raw coal is 820 gigatonnes, of which 2 per cent was established by year-end 1982. The ERCB expects the annual production of bituminous and subbituminous coal to increase to 35 and 34 megatonnes, respectively, by the year 2000.

Electricity

Electric generating and transmission facilities are developed to accommodate the expected growth in demand for electric energy. Sufficient surplus capacity is provided to compensate for plant and transmission line outages while maintaining the desired levels of service. In 1982 the total amount of electric energy generated by the electric utilities in the province was 24 718 gigawatt hours (GW·h). Of this amount, 1590 GW·h was generated by hydro plants, 20 617 GW·h using coal, 2496 GW·h using gas and 15 GW·h using oil (Chart 29). The 1982 peak electrical load in the province was 4093 megawatt hours (MW·h) per hour. ERCB expects Alberta's electrical energy demand to more than double, to approximately 53 thousand GW·h, by the year 2000.

41 Coal Reserves



Revenues/Benefits

. . . earnings and employment resulting from Alberta's energy resources

PRICES

The wellhead or plant gate prices of oil and gas increased in 1982 in accordance with the September 1981 agreement between the federal and Alberta governments. This agreement specified gradual increases in the prices of hydrocarbons to ceiling levels of 75 per cent of world price.

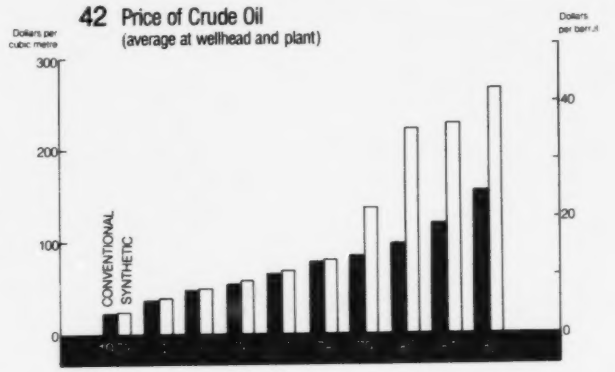
The Canadian price of oil remained below the ceiling level of 75 per cent of world price throughout 1982 (Chart 42). By 1982 the price of conventional crude oil in Alberta had increased to 7 times its 1973 price; the price of synthetic crude oil to more than 11 times its 1973 price.

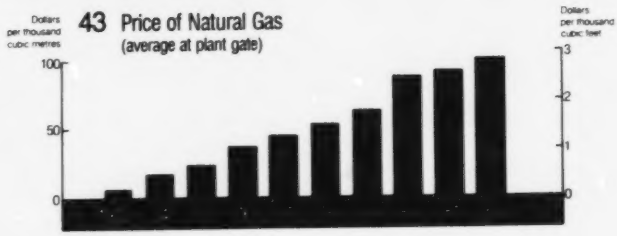
By 1982 the price of marketable natural gas had increased substantially to more than 15 times its 1973 level (Chart 43).

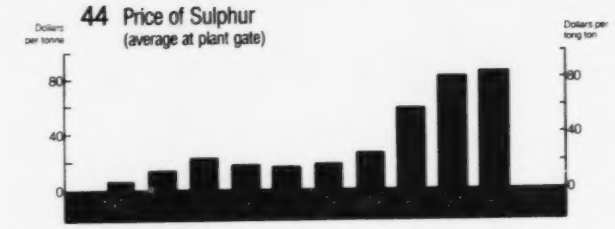
The price of sulphur is determined on world markets by the balance between supply and demand (Chart 44). High demand in the early 1980s led to a quintupling of the 1978 price.

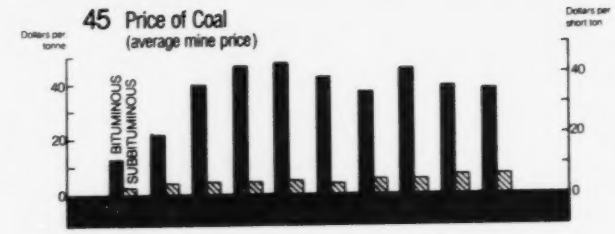
Nearly all subbituminous coal production in Alberta is consumed by electric utilities at a price closely related to the cost of mining. However, most of Alberta's bituminous coal is produced for thermal and metallurgical markets outside Alberta and competes with coal from other countries. As a result the quantities of bituminous coal marketed, and the prices received, tend to fluctuate even though most of the production is marketed under long-term contracts (Chart 45).

The price of electricity in Alberta has increased more rapidly than the overall inflation rate because of the increasing cost of coal-fired generation and higher interest rates.









GROSS REVENUES

The total value of the production of conventional light-medium and heavy crude oil doubled from 1973 to 1977, and doubled again by 1982 as shown in Chart 46. However, this increase in value was due to rising prices rather than increased output.

Chart 47 shows the value of sulphur sales over the period 1973 to 1982. By 1982 sulphur sales had increased to 25 times the 1973 level due to increases in both quantities sold and prices.

The value of synthetic crude oil production increased sharply due to price increases and to the commissioning of the Syncrude plant in 1978 with build-up of its production towards the design capacity of 130 thousand barrels (20 600 cubic metres) per day.

The value of gas production grew even more rapidly due to rising prices and output and, by 1982, was 18 times its 1973 level (Chart 48).

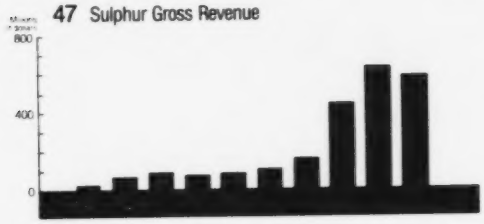
The value of propane and butanes produced has tended to parallel that of gas, although in recent years the rate of increase has been less rapid. The price of these commodities is set in the marketplace, whereas the price of gas sold in markets outside Alberta is set by government policy and is related to crude oil prices (Chart 49).

Revenues from production of coal tend to be dominated by higher priced bituminous coal as shown in Chart 50. Even though coal production has achieved a compound growth rate in excess of 10 per cent, the value of the coal output has not grown as rapidly as that of oil and gas and their by-products.

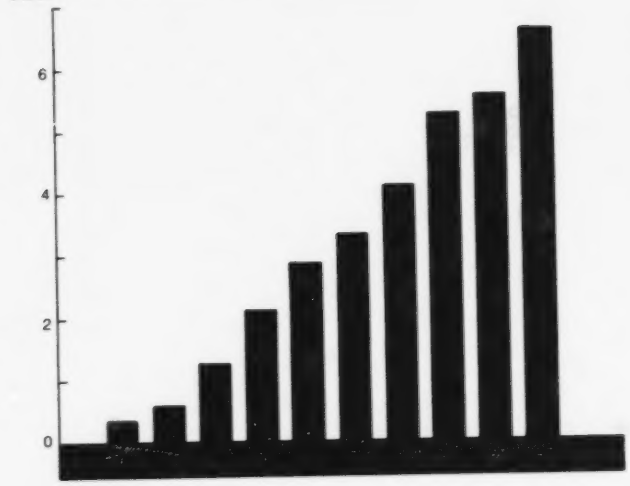
46 Oil Gross Revenue[1]

1 Excluding experimental heavy crude oil and bitumen

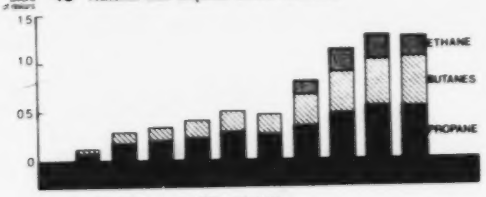
47 Sulphur Gross Revenue



48 Marketable Gas Gross Revenue



49 Natural Gas Liquids Gross Revenue[1]



1 The values of ethane for 1973 through 1976 are not available

50 Coal Gross Revenue

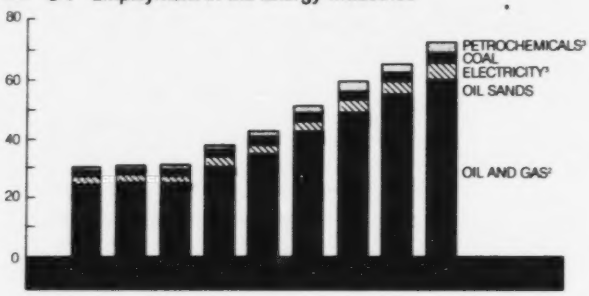
EMPLOYMENT AND INVESTMENT

Chart 51 summarizes employment in the energy industries (excluding pipelines – for which data are not readily available). From 1975 through 1980 there was a steady increase reflecting the expansion of the oil and gas industry during that period. The recent downturn in employment, especially in the drilling and service industries, will be reflected in the employment statistics for 1982 which are not yet available.

Investment statistics presented in Chart 52, like those for employment, show rapid growth over the period 1975-1980 and a levelling in 1981. A decline in the rate of investment also will be evident in the 1982 statistics when they become available.

Thousands

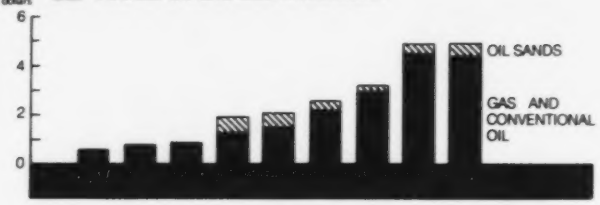
51 Employment in the Energy Industries[1]



1. Data for 1982 are not available.
2. Includes drilling and other services.
3. Estimated for 1981.

Billions of dollars

52 Annual Oil and Gas Investment



Glossary

Coal-Bituminous	- A medium to high grade coal, low in moisture content, that produces when burnt a large amount of heat for a given weight of clean coal compared to that produced by a lower grade coal.
Coal-Subbituminous	- A low to medium grade coal, commonly containing up to about 30 per cent moisture, that produces when burnt a moderate amount of heat for a given weight of clean coal compared to that produced by a higher grade coal.
Coal-Metallurgical	- A bituminous coal with special properties that allow it to be made into coke suitable for reducing ores into metal in the metallurgical industry.
Coal-Thermal	- A coal of any grade that is used for producing heat. The most common use of thermal coal is to produce the steam used in electric generating stations.
Crude Bitumen	- A viscous mixture of hydrocarbons that is not recoverable from an underground reservoir at a commercial rate through a well without special assistance such as by the application of heat.
Crude Oil -Conventional	- A mixture of hydrocarbons that is recoverable from an underground reservoir through a well without special assistance such as by the application of heat.
Crude Oil-Synthetic	- A mixture of hydrocarbons that is derived from crude bitumen.
Development Well	- A well drilled within or close to the limits of a producing or producible pool.
Distribution Lines	- Electric lines of less than 69 kilovolts for distribution of electricity to customers.
Drilling Mud	- Fluid circulated through a wellbore during drilling and workover operations to maintain control of the well and remove drill cuttings and other material.
Electrical Generating Capacity	- Total available output of electrical generation equipment.
Established Reserves	- Those reserves recoverable, with reasonable certainty, under current technology and present and anticipated economic conditions.
Experimental Project	- A project which uses methods that are untried and unproved in a particular application.
Exploratory Well	- Any well other than a development well.
Flow Line	- A pipe (usually buried) through which fluids travel from a well to processing equipment, to storage or to a central delivery point.
Fly Ash	- Those particles of ash that are carried out of a furnace by the exhaust gas stream during the burning of coal.
Fracturing Water	- Water under high pressure used to fracture a formation in order to stimulate production or injection.
Gas Cap	- Free gas overlying an oil zone within the same reservoir.
Heavy Oil	- Oil with a density of 900 kilograms per cubic metre or greater (API gravity of 25 degrees or less).
Initial Volume in Place	- The gross volume of crude oil, crude bitumen, raw natural gas or coal calculated or interpreted to exist in a reservoir before production.
Nitrogen Oxide	- A gaseous compound containing nitrogen and oxygen usually emitted by internal combustion equipment.
Pentanes Plus	- A mixture of mainly pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas condensate or crude oil.
Petrochemical	- A chemical manufactured from petroleum or natural gas or from raw materials derived from petroleum or natural gas.
Price-Wellhead	- The price of oil or gas at the wellhead.
Price-Plant Gate	- The price of gas after processing at a plant.
Primary Energy Source	- An energy resource which is supplied essentially in its raw form.
Process Water	- Water used in an industrial processing operation.
Recovery-Enhanced	- Recovery of a resource where the natural energy is supplemented.
Recovery-Primary	- Recovery of a resource by natural energy or drive mechanisms.
Recovery-Tertiary	- Recovery of a resource where additional energy is employed after an enhanced recovery scheme has been applied or where especially complex means are employed after primary recovery or at any time.
Remaining Established Reserves	- Established reserves less cumulative production.
Reservoir	- A subsurface, porous permeable rock body in which oil or gas, or both, are stored.
Stock Tank Barrel	- A barrel of liquid measured at standard conditions of temperature and pressure.
Sulphur Dioxide	- A toxic gaseous compound containing sulphur and oxygen.
Thermal Power	- Electricity generated by steam which has been produced using hydrocarbon energy resources, such as coal, gas, etc.
Transmission Lines	- Electric lines of 69 kilovolts and greater electrical potential for transmission of bulk energy from generating stations to load centres.
Ultimate Potential	- Established reserves, plus additions expected to existing pools, plus future discoveries expected.
Waterflood	- Enhanced recovery by injection of water.

Units of Measurement

Imperial Equivalent Units

1 cubic metre of oil and pentanes plus (101.325 kilopascals and 15° Celsius)	= 6.293 barrels (35 imperial gallons)
1 cubic metre of natural gas (101.325 kilopascals and 15° Celsius)	= 35.494 cubic feet (14.65 psia and 60° Fahrenheit)
1 cubic metre of ethane (liquid) (equilibrium pressure and 15° Celsius)	= 6.330 Canadian barrels of ethane (liquid) (equilibrium pressure and 60° Fahrenheit)
	= 10.0 thousand cubic feet of ethane gas (14.65 psia and 60° Fahrenheit)
1 cubic metre of butanes (equilibrium pressure and 15° Celsius)	= 6.297 Canadian barrels of butanes (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of propane (equilibrium pressure and 15° Celsius)	= 6.300 Canadian barrels of propane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of water (equilibrium pressure and 15° Celsius)	= 6.290 Canadian barrels of water (equilibrium pressure and 60° Fahrenheit)
1 tonne	= 1.102 short tons (2000 pounds)
	= 0.984 long tons (2240 pounds)
1 kilojoule	= 0.948 British thermal units (Btu)
1 metre	= 3.281 feet
1 kilometre	= 0.621 miles
1 hectare	= 2.471 acres
1 cubic metre of ethane	= 35.310 73 cubic feet of ethane

Prefix	Multiple	Symbol
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Term	Multiple	Symbol
million	10^6	mm
billion	10^9	b
trillion	10^{12}	t
quadrillion	10^{15}	q

ERCB Senior Management – 31 December 1982

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G. J. DeSorcy	Vice Chairman
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E. J. Morin	Manager of Special Projects

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H. Antonio	Data Processing
L. A. Bellows	Development
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R. F. Braun	Employee Relations
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H. J. Webber	Gas
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T. F. Homeniuk	Hydro and Electric
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POOR

QUALITY

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